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From: "Tobias, Lawrence" <LTobias@caiso.com>
To: "Bill Pfanner" <Bpfanner@energy.state.ca.us>
Date: 9/22/2005 1:37:22 PM
Subject: RE: San Francisco Electric Reliability Project hearings?

Bill,

Thank you for the opportunity to comment on the Preliminary Staff Assessment for the San Francisco Electric Reliability Project (04-AFC-1). My comments are as follows, but please, if necessary, have Mark Hesters call me to discuss them as my testimony will include some of the comments and I want to state the facts correctly:

Transmission System Engineering

1. When referring to CA ISO Reliability Criteria, it should be labeled as CA ISO Grid Planning Standards, which include both WECC and NERC reliability criteria and planning standards as well as criteria established through the CA ISO Grid Planning Standards Committee.

2. The Hunters Point Power Plant (both units #1 & #4) will be released from their RMR contracts when that part of the CA ISO's Revised Action Plan for SF is completed. It is expected that the AP-1 Project (a new 115 kV cable between Potrero and Hunters Point Substations) will be completed by the end of 2005 and the Jefferson-Martin 230 kV Line Project within the 1st or 2nd quarter of 2006. The SFERP is associated with Potrero #3's release from its RMR contract and its expected subsequent closure by Mirant. Attached is our Revised Action Plan table as approved by our Board at their Nov. 2004 meeting with the status of projects updated thru August of 2005.

3. For the original site for the SFERP that was within or directly next to Potrero Substation, there was a System Impact Study, Facilities Study and an Updated Facilities Study conducted. For the present site, a Feasibility Study and 2nd Updated Facilities Study were conducted. My letter to PG&E on June 27, 2005 referred to their Feasibility/Updating Facility Study II. This last Facilities Study captured the present list of interconnection facilities for the present site for the SFERP.

4. With Potrero Unit #7 on-line as well as the SFERP, an additional and 2nd 115 kV cable between Potrero and Hunters Point Substations would be required. One cable between these substations should be in operation by the end of 2005. Please cross-check with PG&E to be sure that I am correct on this.

Local System Effects

1. Again, the SFERP is associated with Potrero #3 released from its RMR contract per the attached Revised Action Plan table. Information may be available from Mirant to describe what cost reduction to ratepayers may be achieved without this unit under an RMR contract.

2. With the SFERP as a replacement for existing and old generation in SF (Potrero Unit #3) there should not be a reduction in system losses as Potrero #3 can generate as much as 210 MW and the three CT's comprising the SFERP will be capable of 195 MW, thus losses may increase very slightly with the SFERP. I am not familiar with the voltage support increase with the SFERP, but it may not be significantly different than Potrero #3. Mark Hesters could check on this for you.

3. The present 1-in-10 year load forecast for the SF Area as defined by PG&E for their 2005 annual transmission studies is projected to be 945 MW in 2007.

4. Hunters Point Units #2 & #3 have been shut down by PG&E as a result of their Potrero Staic Var Device Project coming on-line by the end of 2004.

5. The 230 kV lines from Tesla & Newark connect to Ravenswood Substation which in turn is connected to San Mateo Substation by two 230 kV lines as well as parallel 115 kV lines.

6. If the SFERP is not permitted, the ISO would re-evaluate the whole of its Revised Action Plan that is associated with Potrero Units 3,4,5,& 6. Per the CAISO San Francisco Greater Bay Area Generation Outage Standard (attached), without the SFERP, potentially all of the existing Potrero generator units would be retained to account for an overlapping outage of Potrero #3 and one of the Potrero CT's along with a transmission line out. This would insure that our 100 MW requirement for generation would be available. This 100 MW is associated with our Revised Action Plan and would be achievable with the SFERP in that we would assume only one of the new CT's at Potrero would be out in an over-lapping outage with a transmission line and therefore leave about 100 MW of generation on-line. For this situation, we are also including the CCSF CT that is planned to be sited near the SF Airport.

I appreciate having the opportunity to comment and send them to you.

Thanks

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-----Original Message-----
From: Bill Pfanner [mailto:Bpfanner@energy.state.ca.us]
Sent: Thursday, September 15, 2005 4:10 PM
To: Tobias, Lawrence
Cc: Mark Hesters
Subject: Re: San Francisco Electric Reliability Project hearings?

Larry. Please respond to the SFERP PSA directly to me. It would be appreciated if you could respond by Oct. 14th. Thanks

>>> "Tobias, Lawrence" <LTobias@caiso.com> 09/15/05 4:02 PM >>>

Bill,

I just got a copy of the PSA for the San Francisco Reliability Project and am inquiring about both who I should send my testimony on Transmission Engineering to at the CEC for review and when it is required. Today, I started drafting it and expect it can be completed quickly if necessary.

My understanding is that my testimony will be sponsored through the CEC in conjunction with the CEC's review of transmission engineering. I reviewed the last version of the second Revised Facilities Study Report for interconnecting this project and therefore my testimony will primarily be about by review and approval for interconnecting this project to the electric grid through PG&E's Potrero Substation.

Thanks

Larry

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Attachment A

CAISO Revised Action Plan for San Francisco

PG&E Transmission Projects and City Peaking Power Plants Necessary
To Meet NERC/WECC/CAISO Planning Requirements

AS OF SEPTEMBER 2, 2005

	Project	Estimated Completion Date/Status	Issue	Resolution of Issue
Release Hunters Point Units 2 & 3 From Their RMR Agreements				
1	Potrero Static VAR Compensator	December 2004, Completed	NERC/WECC/CAISO Planning Standards	This project allowed ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 2 and 3 released from their RMR Agreement
Release Hunters Point Units 1 & 4 From Their RMR Agreements				
2	San Mateo-Martin No. 4 Line Voltage Conversion	Completed	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
3	Ravenswood 2nd 230/115 kV Transformer Project	Completed	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
4	San Francisco Internal Cable Higher Emergency Ratings	Completed: To Be Used Upon Completion of the Jefferson-Martin 230kV Project	NERC/WECC/CAISO Planning Standards	These ratings are an interim solution that in combination with the other listed projects allows PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreements. In 2007, a third Martin-Hunters Point 115 kV cable will replace the emergency ratings.
5	Tesla-Newark No. 2 230 kV Line Reconductoring	February 2005, Completed	RMR Criteria	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
6	Ravenswood-Ames 115 kV Lines Reinforcement	April 2005, Completed	RMR Criteria	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement

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7	San Mateo 230 kV Bus Insulator Replacement	May 2005, Completed	Operations Requirement During San Mateo Bus Wash	Eliminate bus wash at San Mateo 230 kV bus will reduce the 400 MW generation operational requirement down to less than 200 MW

8	Potrero-Hunters Point (AP-1) 115 kV Cable	December 2005 CPUC Permit Approval Granted	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement. Scheduled for Dec. 2005 operation.
9	Jefferson-Martin 230 kV Line	March '06 to June '06 Under construction	NERC/WECC/CAISO Planning Standards	This project in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreement
10	Potrero 3 SCR retrofit	June 2005 Completed	NERC/WECC/CAISO Planning Standards	This project ensures the availability of Potrero 3 at full capacity thereby reducing overall Greater Bay Area RMR requirements. This project or the reduced capacity available without the retrofit in combination with the other listed projects allows ISO/PG&E to meet planning requirements with Hunters Point Power Plant Units 1 and 4 released from their RMR Agreements
Release Potrero Unit 3 From Its RMR Agreement				
11	San Francisco Electric Reliability Project and San Francisco Airport Electric Reliability Plant	June 2007	NERC/WECC/CAISO Planning Standards	These projects will allow ISO/PG&E to meet planning requirements with Potrero 3 released from its RMR Agreement. CEC permit suspended due to a change in where to site near Potrero.
Release Potrero Units 4, 5, & 6 From Their RMR Agreements (assumes previous completion of Peaking Power Plants by the City)				
12	Upgrade the Newark-Dumbarton 115kV line	December 2006 Engineering in Progress	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement
13	Upgrade the Bair-Belmont 115kV Line	Scheduled for May 2007	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement
14	Upgrade the Metcalf-Hicks & Metcalf-Vasona 230 kV lines	Scheduled for May 2007	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement
15	Add voltage support at Ravenswood substation	Scheduled for May 2007	NERC/WECC/CAISO Planning Standards	This upgrade is needed in combination with the other listed mitigations to allow ISO/PG&E to meet planning requirements with Potrero Units 4, 5, and 6 released from their RMR Agreement

CALIFORNIA ISO

PLANNING STANDARDS

February 7, 2002

Table of Contents

California ISO Planning Standards

I. Introduction

The purpose of this document is to specify the Planning Standards that will be used in the planning of ISO Grid transmission facilities. The primary principle guiding the development of the ISO Grid Planning Standards is to develop a consistent reliability standards for the ISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-ISO planning standards.

The ISO Tariff specifies:

> "After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs, will work to develop a consistent set of reliability criteria for the ISO Controlled Grid which the TOs will use in their transmission planning and expansion studies or decisions."[1]

The ISO Tariff specifies in several places that the facilities that are to be added to the ISO Grid are to meet the Applicable Reliability Standard, which is defined as follows:

> "The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC."[2]

These ISO Grid Planning Standards fill the role of the "consistent set of reliability criteria" in the above tariff language. To facilitate the development of these Standards, the ISO formed the ISO Grid Planning Standards Committee (PSC), which includes representation from all interested market participants. One of the primary roles of the PSC is to periodically review the ISO Grid Planning Standards and recommend changes as necessary. In recognition of the need to closely coordinate the development of the ISO Grid with neighboring electric systems both inside and outside of California, the approach taken by the PSC is to utilize regional (WSCC) and continental (NERC) standards to the maximum extent possible. These ISO Grid Planning Standards build off of, rather than duplicate, Standards that were developed by WSCC and NERC. The PSC has determined that the ISO Grid Planning Standards should:

- Address specifics not covered in the NERC/WSCC Planning Standards.
- Provide interpretations of the NERC/WSCC Planning Standards specific to the ISO Grid.
- Identify whether specific criteria should be adopted that are more stringent than the NERC/WSCC Planning Standards.

The following Section details the ISO Grid Planning Standards. Also attached are interpretations of the terms used by NERC and background information behind the development of these standards.

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[1] ISO Tariff, October 13, 2000, Section 3.2.1.2, Original Sheet No. 144.

[2] ISO Tariff, October 13, 2000, Appendix A, Original Sheet No. 303.

II. ISO Grid Planning Standards

The ISO Grid Planning Standards include the following:

1. **NERC/WSCC Planning Standards -** The standards specified in the NERC/WSCC Planning Standards unless WSCC or NERC formally grants an exemption or deference to the ISO.

2. **Specific Nuclear Unit Standards -** The criteria pertaining to the Diablo Canyon and San Onofre Nuclear Power Plants, as specified in Appendix E of the Transmission Control Agreement.

3. **Combined Line and Generator Outage Standard -** A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.

4. **New Transmission versus Involuntary Load Interruption Standard**

   A. Involuntary load interruptions are not an acceptable consequence in planning for ISO Planning Standard Category B disturbances (either single contingencies or the combined contingency of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly not cost effective (after considering all the costs and benefits). In any case, planned load interruptions for Category B disturbances are to be limited to radial and local network customers as specified in the NERC Planning Standards.

   B. Involuntary load interruptions are an acceptable consequence in planning for ISO Planning Standard Category C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly cost effective (after considering all the costs and benefits).

   C. In cases where the application of Standards 4A and 4B would result in the elimination of a project or relaxation of standards that would have been built under past planning practices, these cases will be presented to the ISO Board for a determination as to whether or not the projects should be constructed.

5. **San Francisco Greater Bay Area Generation Outage Standard -** Before conducting Grid Planning studies for the San Francisco Greater Bay Area, the following three units should be removed from service in the base case:

   - One 50 MW CT in the Greater Bay Area but not on the San Francisco Peninsula.
   - The largest single unit on the San Francisco Peninsula.
   - One 50 MW CT on the San Francisco Peninsula.

   The case with the above three units out of service should be treated as the "system normal" or starting base case (NERC Category A) when planning the system. Traditional contingency analysis, based on the standards specified in the NERC, WSCC (including voltage stability), and ISO standards (such as single line outage, single generator outage etc), would be conducted on top of this base condition. The one exception is that when screening for the most critical single generation outage, only units that are not on the San Francisco peninsula should be considered. Similarly, when examining multiple unit outages, at least one of the units considered should not be on the San Francisco Peninsula.

This standard is intended to apply to system planning studies and not system operating studies. In addition, this standard has not been designed to be used to determine Reliability Must-Run generation requirements. The RMR standards are intentionally developed separately from the Planning Standards.

It is recognized that it may require several years to add the facilities to the system that are necessary to allow the system to meet this standard. The amount of time required will depend on the specific facility additions this standard generates.

III. ISO Grid Planning Guides for New Generator Special Protection Systems

As stated in the NERC/WSCC Planning Standards, the function of a Special Protection System (SPS) is to: "detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance." In the context of new generation projects, the primary action of a SPS would be to detect a transmission outage (either a single or credible multiple contingency) or an overloaded transmission facility and then trip or run back generation output to avoid potential overloaded facilities or other criteria violations. The alternatives to a SPS are pre-contingency generation curtailment or new transmission facilities.

The primary reasons why a SPS might be selected over new transmission facilities are that a SPS can normally be implemented much more quickly and for a much lower cost. In addition, a SPS can increase the utilization of the existing transmission facilities and make better use of scarce transmission resources. Due to these advantages, a SPS is an alternative commonly proposed as a cost-effective method of integrating new generation into the grid while maintaining system reliability. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of a SPS, there can be increased exposure to potential criteria violations, transmission outages can become more difficult to schedule, and the system can become more difficult to operate. If there are a large number of SPSs, it may become difficult to assess the interdependency of these SPSs on system reliability. It is these reliability concerns that have led to the development of the additional guides in this document concerning the application of SPS. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of the existing transmission facilities while maintaining system reliability and operability. The need for these guides has become more critical as a result of the large number of new generators that are currently planning to connect to the ISO Grid.

It needs to be emphasized that these are guides rather than standards. This is to emphasize that judgement will need to be used by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of a SPS in all potential applications.

California ISO New Generator SPS Guides

ISO G1. The overall reliability of the system should not be degraded after the combined addition of the SPS and the generator.

ISO G2. The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. To meet this requirement, the SPS may need to be fully redundant.

ISO G3. The SPS must be fully automatic, including arming, as much as practical.

ISO G4. The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the maximum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and may increase or decrease. In addition, the actual amount of generation that can be tripped is project specific and may depend on the reliability criteria violations to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts shown in this guide. The net amount of generation is the gross plant output less the load (plant and other) tripped by the same SPS.

ISO G5. For SPSs designed to protect against single contingency outages, the following consequences are normally unacceptable should the SPS fail to operate correctly (even for a fully redundant SPS):

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the line the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.
B) Voltage instability, transient instability, or small signal instability: While these are rarely concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

These restrictions apply to single contingency outages and not double contingency outages due to the much higher probability of occurrence of single contingency outages.

ISO G6. Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno etc) and grid-wide need to be evaluated as a whole and studied as such.

ISO G7. The SPS must be simple and manageable. Generally, there should be no more than 4 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS and the SPS should not be monitoring the loading on more than 4 system elements. The exception is that if the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements, then the new generation cannot materially increase the complexity of the existing SPS scheme. Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided, if possible.

ISO G8. The SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO G9. Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment or to the loading levels that would exist on the system prior to the addition of the new generator. For example, the operation of a SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back generation to bring the line loading to be within the line's 4 hour or longer rating.

ISO G10. The SPS should not run-back or trip existing Reliability Must-Run generators unless there is no plausible expectation that the ISO would call upon such generators for reliability purposes during the periods where the SPS would be armed.

ISO G11. The SPS needs to be approved by the ISO and may need to be approved by the WSCC Remedial Action Scheme Reliability Task Force.

ISO G12. The CA-ISO, in coordination with affected parties, may relax SPS requirements as a temporary bridge to system reinforcements. Normally this bridging period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of a SPS requirement would be to allow 6 initiating events rather than limiting the SPS to 4 initiating events.

ISO G13. The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO G14. In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies).

ISO G15. The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO G16. All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation. To facilitate transmission system studies, documentation will be made available to others upon request to the ISO.

ISO G17. Normally, the transmission owner, in coordination with affected parties, will be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO G18. Generally, the generating units tripped by the SPS should be highly effective in reducing the loadings on the facilities of concerns.

ISO G19. Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO will normally be required. Specific telemetry requirements will be determined on a project specific basis.

IV. Interpretations of NERC/WSCC Planning Standard Terms

Listed below are several of the terms that are used in the NERC Planning Standards which members of the PSC have determined require clarification. Also provided below are ISO interpretations of these terms:

Bulk Electric System: The ISO Bulk Electric System refers to all of the facilities placed under ISO control.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTOs and the ISO subject to appropriate coordination and review with the relevant state, local, and federal regulatory authorities and WSCC. The PTOs develop annual transmission plans, which the ISO reviews. Both the ISO and PTOs have the ability to identify transmission upgrades needed for reliability.

Entity Required to Develop load models: The TOs, in coordination with the UDCs and others, develop load models.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. The PSC decided that for studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a higher standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified in the ISO Grid Coordinated Planning Process and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

V. Background behind the New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under some contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of specific single contingencies. Historically, there has been a wide variation in approaches exists among the California ISO PTOs. One PTO may allow involuntary loss of load following a specific type of contingency while another PTO would build a project to prevent loss of load for the same type of contingency. This standard is intended to lead to the elimination of these inconsistencies and also to provide the information needed to help ensure that the ISO is making cost effective transmission system additions.

This standard is also a change in the approach the ISO uses in planning from primarily deterministic planning standards[3] toward probabilistic planning standards. It is the general belief of the PSC that this trend will be an improvement in that it will provide additional information for the ISO and others to use when making decisions associated with making improvements to the grid. It is the intent of the PSC that the implementation of these principles should not result in lower levels of reliability to end-use customers than existed prior to restructuring.

To implement this standard, the following process will be used:

1) Identification of Reliability Concerns: As part of the PTO's annual transmission expansion plans, each PTO will identify those ISO Category B outages that would require the involuntary interruption of load either as a result of the system configuration (i.e., such as for a radial system) or because interrupting load was necessary to meet the ISO Grid Planning Standards.

2) Information Gathering: For each of the ISO Category B outages that required involuntary interruption of load, the PTOs will estimate the following:

- The maximum amount of load that would need to be interrupted
- The duration of the interruption
- The annual energy that would not be served or delivered
- The number of interruptions per year
- The time of occurrence of the interruption (e.g., weekday summer afternoon)
- The number of customers that would be interrupted
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural)
- Value of Service or Performance Based Ratemaking assumptions concerning the dollar impact of a load interruption

[3] An example of a purely deterministic standard is the following: There should be no more than 200 MW of load loss for a double contingency.

The above information will be documented in the PTO's Transmission Expansion Plans. Using this information, the PTOs and other interested stakeholders can estimate the benefit to the end-use customers of reducing the likelihood of interruption.

3) PTO Recommendations: As part of the evaluation of alternatives in the PTO's Five-Year Transmission Expansion Plans, the PTOs will propose either projects or operating procedures[4] to be the appropriate solution to address identified reliability criteria violations. The PTOs shall also provide their rationale for selecting either an operating procedure or a project.

4) Cost-Benefit Estimates: The PTO will estimate the costs[5] and benefits of projects to remedy the reliability concerns identified in 1) above. In addition to developing new projects, the PTOs will review currently approved projects to determine if they would still propose to construct those projects or propose an alternative solution.

For cases where the PTO has proposed an operating procedure that involves the interruption of load to be the appropriate solution, the PTOs will estimate the following:

- The future frequency and duration of outages for impacted substations
- The historical frequency and duration of outages for impacted substations
- The communities served by these substations

5) Notification: All of the above information will be provided to the stakeholders as part of the Transmission Expansion Plan prior to an ISO decision to accept or reject PTO-proposed involuntary load dropping in lieu of transmission reinforcement. The information will be made available in a timely manner so that customers can intervene before the ISO Board if they desire.

One way the information could be provided would be to develop a table such as the following:

<u>Projected and Historical Reliability Data for Single Contingencies that can Result in Load Interruptions</u>

Case	Area Affected		Possible Future Outage Without Project		Possible Future Outage With Project	
	Substations, Feeders, And Peak MW	Communities	Frequency	Duration	Frequency	Duration

[4] The proposed operating procedures shall be in sufficient detail in concept and application so as to allow review and approval in principle in lieu of upgrade projects.
[5] Project costs may need to be handled as confidential information.

6) ISO Review and Approval: The ISO, with input from the PTOs and other stakeholders, will review the PTO's five-year plans and determine whether to adopt the PTO's proposed projects or operating procedures[6]. The final ISO approved plan will be distributed to the stakeholders.

7) Periodic Reevaluation: Cases where it has been decided by the ISO Board to plan for involuntary load interruptions rather than a project (transmission, generation, or load reduction) will be re-evaluated every three years or more frequently if merited by load growth or system changes or if the reliability in that area has significantly deteriorated.

[6] Proposed operating procedures will be reviewed by the ISO to determine whether they can be reasonably implemented.

VI. Background behind the San Francisco Greater Bay Area Generation Outage Standard

On June 14, 2000, rolling blackouts were initiated in the San Francisco Bay area to protect against the potential for voltage collapse. The major reason behind the need to implement rolling blackouts was the large number of generating units that were forced out of service on that day. The problem had not been uncovered in the planning studies for the area because the current ISO Grid Planning Standards only require that a single generating unit be assumed out of service in combination with the most critical transmission line. As a result of the June 14, 2000 rolling blackouts, the ISO Grid Planning Standards Committee was tasked with reviewing the ISO Grid Planning Standards to determine whether they need to be revised.

As a result of this review, the ISO Grid Planning Standards Committee determined that, while the normal standard of planning for one generating unit in combination with one transmission line out is adequate for most of the ISO Grid, it is inadequate for the greater San Francisco Bay area. In the Bay area, there is an unusually large concentration of generating units (more than 30) which increases the likelihood that more than one unit could be forced out of service at a given time. In addition, the historical forced outage rates for the units in the Bay area are significantly higher than the industry averages for similar units resulting in a higher probability of such multiple outage occurrences. The higher forced outage rates are at least partially due to the age of the units. Based on this information, and discussion at six stakeholder meetings where a variety of approaches to potential new standards were considered, the San Francisco Greater Bay Area Generation Outage Standard was developed.

While this proposed standard only applies to the San Francisco Bay Area, the ISO Grid Planning Standards Committee will periodically review various areas of the ISO Grid to determine if additional specific standards are warranted to address issues unique to those areas.

The ISO Grid Planning Standards Committee will review this standard periodically. This review will require forced and scheduled outage data for all generating units in the area.

The following tables provide the statistical basis for the work that has been completed by the ISO Grid Planning Standards Committee. This data was provided by PG&E and is based on outage data available to PG&E during their ownership of the units prior to the formation of the CAISO. It is assumed for this analysis that outage data will be similar under the present ownership of the units. For a description of how the data was compiled or computed, please refer to the original report that was prepared by Anatoliy Meklin of PG&E. The report is entitled "STATISTICAL ANALYSIS OF SIMULTANEOUS FORCED OUTAGES IN BAY AREA" and dated October 31, 2000.

Table 1. Forced Outage Data for Bay Area Generators

Name	MW	T2 - hours between forced outages		T1 - hours of forced outages	
		Mean	Standard deviation	Mean	Standard deviation
OAKLND 1	55	2130	1978	521	1150
OAKLND 2	55	4804	6612	306	649
OAKLND 3	55	4352	4399	29	17
ChevGen1	54	1475	1032	25	18
ChevGen2	54	1475	1032	25	18
PDEFCT2	199	1475	1032	25	18
PDEFCT1	199	1475	1032	25	18
PDEFST1	280	1475	1032	25	18
PTSB 1	170	1720	2078	79	75
PTSB 2	170	2448	1986	622	1925
PTSB 3	170	1520	1549	570	873
PTSB 4	170	2307	2048	153	138
PTSB 5	325	1798	2389	262	373
PTSB 6	325	4596	3773	67	48
PTSB 7	710	3252	6196	147	131
MOSS 5	750	2735	1416	64	35
MOSS 6	750	1626	1970	94	94
C.COS 6	340	1930	1522	429	1365
C.COS 7	340	1158	843	41	57
POTRERO3	210	3090	3156	212	186
POTRERO4	52	4705	6151	253	242
POTRERO5	52	13090	6869	75	35
POTRERO6	52	5596	9842	47	41
HNTRS P2	108	2047	1961	129	160
HNTRS P3	108	3207	4253	76	51
HNTRS P4	170	3165	4511	130	146
HNTRS P1	52	7856	7498	55	31
GLRY COG	130	1445	1010	55	38
FMC CT	52	1445	1010	55	38

Table 2. NERC Forced Outage Data for Selected Types of Units

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	FOF (%)	Assuming 6 outages per year	
					T2 - hours between forced outages	T1 – hours of forced outages
FOSSIL	All Sizes	1,532	7,126	3.82	1408	56
All Fuel Types	1-99	351	1,486	3.18	1417	47
	100-199	426	2,016	3.45	1413	51
	200-299	171	825	3.68	1410	54
	300-399	147	717	5.07	1390	74
	400-599	262	1,250	4.29	1401	63
	600-799	127	602	4.22	1402	62
	800-999	34	165	3.48	1413	51
	1000 Plus	14	65	5.78	1379	85
Gas Primary	All Sizes	466	1,965	3.58	1412	52
	1-99	145	554	3.53	1412	52
	100-199	147	624	3.61	1411	53
	200-299	47	211	2.31	1430	34
	300-399	41	188	4.33	1401	63
	400-599	63	296	3.92	1407	57
	600-799	20	81	4.27	1401	63
	800-999	3	11	1.50	1442	22
Gas Turbine	All Sizes	768	3,475	3.84	1408	56
	20-49	251	1,161	5.60	1382	82
	50 Plus	318	1,386	2.12	1433	31
Comb. Cycle	All Sizes	58	242	1.50	1442	22

Table 3. Probabilities of Simultaneous Forced Outages of Generators
(Actual Greater Bay Area Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	91	8.1
>=2	68	6.2
>=3	40	3.7
>=4	17	1.6
>=5	6	0.6

Observations:

- One out of 30 generators is unavailable 91 % of time
- The probability of simultaneous forced unit outages is very high and two units are unavailable 68% of the time
- The coincident forced outage of 5 generators could occur for 520 hours/year or 52 peak-hours/year.
- The probability of having 5 generators forced out of service in the Greater Bay Area is 20 times higher using actual historical data than it would be if the units had typical NERC forced outage rates as shown in Table 4.

Table 4. Probabilities of Simultaneous Forced Outages of Generators
(NERC Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	67	5.8
>=2	28	2.4
>=3	8.3	0.72
>=4	1.59	0.15
>=5	0.22	0.03

Observations:

- The lower generator forced outage rates in the NERC data result in a much lower probability for multiple unit outages.

Table 5. Probabilities of Simultaneous Forced Outages of Megawatts (Using Actual Data).

Unavailable MW	% of year	% of year if in peak	occurrences/year	occurrences/year if in peak
in forced outage			(as result of a forced outage event with loss of >100 MW)	(as result of a forced outage event with loss of >100 MW)
>=100	88.2	7.7	60.44	5.55
>=200	74.9	6.4	54.31	4.8
>=300	66.2	5.65	49.93	4.48
>=400	48.3	4.07	40.30	3.71
>=500	42.6	3.56	35.92	3.30
>=600	28.8	2.4	26.28	2.53
>=700	20.7	1.69	20.15	2.07
>=800	15.2	1.21	20.15	1.59
>=900	10.8	0.92	12.26	1.31
>=1000	8.0	0.69	9.64	1.05
>=1100	5.5	0.46	7.01	0.61
>=1200	4.0	0.34	5.26	0.44
>=1300	2.7	0.21	3.50	0.32
>=1400	1.8	0.12	2.63	0.22
>=1500	0.9	0.07	1.75	0.16
>=1600	0.6	0.04	0.88	0.11

Note: Peak hours make up about 8.8% of the year.

REDNOVA

Edison Pulls Plug on Plants

Sep. 22--Although Southern California needs more power plants to support its booming growth, it is uncertain how they will get built.

That uncertainty was underscored this week when Southern California Edison Co. cancelled its request for long-term electricity contracts that were expected to spur the development of 1,500 megawatts of new generation capacity.

The utility said late Tuesday it withdrew the contract request it had launched in April because the California Public Utilities Commission opposed Edison's controversial plan to spread the cost of the contracts to everyone in Southern California who depends on the same power grid for electricity.

Southern California Edison argued that because the new power plants would increase the reliability of the grid, everyone served by the grid should pay for the electricity through their rates.

San Diego Gas and Electric, municipal utilities in Riverside and Colton and independent power sellers were asked to help Edison pay for the plants.

However, the Public Utilities Commission said it is not interested in having Edison serve as a buyer of last resort for other utilities and energy service providers in Southern California.

The commission also said Edison has estimated that its own customers will need about 1,000 megawatts of the 1,500 megawatts of new generation that would be built under the proposed long-term contracts.

The commission won't know until it reviews the resource plans of utilities and energy service providers in January whether the additional 500 megawatts for which Edison wanted to contract will be needed, said commission spokeswoman Teri Prosper.

The commission advised Edison it could contract for 1,000 megawatts of electricity for its own customers, Prosper said. But Edison said it would no longer seek long-term contracts and would "continue to meet customers needs through short and medium term contracts," which generally do not support new power plant construction.

"We were attempting to help the state address a serious power supply dilemma -- inadequate new plant construction in Southern California," Southern California Edison Chief Executive Alan Fohrer said this week in announcing the withdrawal.

Pedro Pizarro, Edison's vice president of power procurement said in April that Edison's proposal was meant to share the financial risk of building new power plants. He said since the state's 2001 power crisis, power producers have not been able to obtain financing for new plants unless they have long-term contracts to sell the generation.

But Pizarro said Edison was unwilling to award long-term contracts because it was uncertain how many customers it would have in the future. The uncertainty, he said, stemmed from legislative efforts to allow more Edison customers to shop for power elsewhere.

Bob Finkelsein, executive director of The Utility Reform Network, a San Francisco-based consumer advocacy group, sympathized with Edison. He said as long as there is a threat of further deregulation, "Edison doesn't have sufficient certainty about who will remain their customers."

Finkelstein said because the commission had problems with Edison's approach, it would be up to the commission to find an alternative that will get power plants built.

Aaron Johnson, senior energy advisor to Commissioner Dian Grueneich, who issued the ruling on Edison's contracting proposal, said the commission has established a method for protecting utility investments in new generation by requiring any customers who leave their service to pay an exit fee.

Johnson said the method for protecting utility investments in power plants was first adopted when the PUC approved Edison's plans for building the 1,054-megawatt Mountainview power plant under development in Redlands, which is expected to begin operation next year.

Jan Smutny-Jones, executive director of the Independent Energy Producers Association, said Southern California's demand for electricity grew by more than 5 percent last year, more than twice the national average rate, because of a rebounding economy and expansion of development into inland regions with greater air conditioning requirements.

"The lion's share of load growth is in (Southern California) Edison territory," Smutny-Jones said.

State Energy Commission estimates California will require 5,000 megawatts of new electricity by 2016. One megawatt is enough energy for up to 1,000 homes.

Source: California Independent System Operator.

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